

Analysis of In-Situ Stress Regime in the Alberta Basin, Canada, for Performance Assessment of CO₂ Geological Sequestration Sites

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ABSTRACT

Oil and gas reservoirs and deep saline aquifers are primary candidates for long-term geological sequestration of greenhouse and acid gases. Risk assessment for sequestration projects must include predictions of sequestration zone performance. These performance assessments will guide the selection of sequestration sites and/or operating parameters, such as injection pressure and rate, that mitigate leakage risks. If natural fractures or faults are present, then bottom-hole injection pressures higher than the minimum in-situ stress may open these fractures. Pressures higher than the fracture breakdown pressure will fracture the reservoir and/or caprock. In both cases, CO₂ or acid gas will leak from the sequestration unit. Thus, it is essential to properly estimate the minimum stress and fracture breakdown pressure and devise injection strategies that will maintain pressures below these at all times.

An extensive database of micro- and mini-fracture, leak-off and fracture breakdown pressures measured by industry in the Alberta Basin, Canada, and data from close to fifty acid-gas injection operations in the basin has been used to develop a methodology for estimating the minimum in-situ stress both at regional and local scales throughout the basin on the basis of these data. Minimum horizontal stress gradients close to 17 kPa/m have been estimated for much of the basin from leak-off tests conducted over depths from ~250 to ~1000 m. Gradients close to 13 kPa/m have been estimated for depths ranging from ~1000 to ~2500 m from fracture breakdown pressures that are believed to be affected by reservoir production and pressure depletion. Approved maximum bottom-hole injection pressures at the acid-gas injection operations in western Canada are safely below the minimum horizontal stress, thus avoiding re-opening pre-existing fractures, if any exist. Since minimum horizontal stresses are lower by 12.3% on average than rock fracturing pressures, new fractures will not be induced as a result of injection. Using similar operating requirements for CO₂ injection will ensure the mechanical safety of CO₂ geological sequestration operations.

1. INTRODUCTION

Implementation of technologies to capture carbon dioxide (CO₂) and sequester it in geological formations will be necessary in order to achieve significant reductions in atmospheric emissions of anthropogenic greenhouse gases. Oil and gas reservoirs and deep saline aquifers (collectively referred to as *sequestration reservoirs* in this paper) are primary candidates for long-term geological sequestration. By ratifying the Kyoto protocol, Canada has committed to reduce by 2012 its greenhouse gas emissions to 6% below the 1990 level, although currently emissions are approximately 20% above that level. Carbon dioxide emissions in the province of Alberta represent approximately 30% of Canada's emissions. Unlike in other provinces, two thirds of these emissions are from large stationary sources, such as coal-fired power plants, refineries and oil sands plants, that are conducive to CO₂ capture and sequestration in the Alberta Basin that underlies the province (Bachu and Stewart, 2002).

If the CO₂ injected into sequestration reservoirs leaks to the atmosphere in significant quantities, then the operation will have failed to mitigate the global effect of global warming, its very purpose of being implemented. Locally, leaked CO₂ may contaminate other energy and mineral resources in the sedimentary succession, and potable groundwater resources if it reaches shallow zones. In extreme cases, where high-rate leakage occurs through a localized conduit to the surface, CO₂ may endanger life. Thus, it is essential to assess the potential for CO₂ leakage and to implement site selection criteria and operating parameters that would mitigate the possibility of CO₂ escaping from the sequestration reservoir. Risk analysis is an integral component of this assessment. It involves an evaluation of the types of events that may result in leakage, the likelihood of these events, and their potential consequences. Risk analysis for

greenhouse gas sequestration is currently in its early stages, with most of the emphasis being placed on performance assessment (i.e., identifying events and their likelihoods), and less on consequences (e.g., Chalaturnyk *et al.*, 2004). Similarly, this paper deals with selected, important aspects of performance assessment, more specifically, the identification of possible leakage events that are controlled by the geomechanical integrity of the low-permeability caprock that seals the sequestration reservoir, and methods for mitigating the likelihood of these events. The potential for leakage through wellbores due to factors controlled by geomechanical parameters is also discussed. Other, important aspects of leakage through wellbores (e.g., well abandonment procedures, chemical interaction between CO₂ and well casings and cements) are not considered here.

The geomechanical integrity of the sequestration reservoir is controlled by the stress regime at the site and by operating parameters such as bottom-hole injection pressure. Stresses are tensorial in nature and are characterized by the three principal components, σ_1 , σ_2 and σ_3 , which are orthogonal, and by their orientations. By definition, one of the principal stresses must intercept free surfaces, such as the ground surface, at right angles. Thus, in the case of divergent sedimentary basins (e.g., foreland, intra-cratonic, platform-margin) with gentle surface relief, a basic assumption is that the ground surface is semi-planar and sub-horizontal; hence the principal stress directions are approximately vertical and horizontal. In this case, the principal stresses are denoted by σ_v for the vertical stress, and σ_{Hmin} and σ_{Hmax} for the smaller and larger horizontal stresses, respectively. This assumption is not valid in the case of convergent sedimentary basins (e.g., in subduction areas and intramontane belts), in the vicinity of major fault zones that deflect stresses, around salt domes or in overthrust and deformed zones. The assumption of vertical and horizontal principal stresses applies to the Alberta Basin in Canada east of the Rocky Mountain Deformation Front. In most sedimentary basins σ_{Hmin} is less than σ_v , and indeed previously published stress magnitude measurements in the Alberta Basin indicate that the smallest principal stress, σ_3 , is horizontal (i.e., $\sigma_3 = \sigma_{Hmin}$) except possibly in parts of the foothills and in the shallow part of the basin in northeastern Alberta near the edge of the basin at the Canadian Precambrian Shield (Bell and Babcock, 1986; Bell *et al.*, 1994; Bell and Bachu, 2003). This means that natural and induced fractures will be vertical and oriented in a direction perpendicular to σ_{Hmin} (i.e., along the trajectory of σ_{Hmax}). Only at shallow depth, less than 300 m, σ_v may be less than σ_{Hmin} , in which case fractures will be horizontal.

2. LEAKAGE MECHANISMS CONTROLLED BY IN-SITU STRESSES

Following is a brief summary of leakage mechanisms that are relevant to this paper, illustrated in Figure 1. For a more complete discussion, the reader is referred to Hawkes *et al.*, (2004). Presumably, the initial selection of a sequestration reservoir would include an assessment of the presence of faults or natural fractures. Ideally, sequestration sites without any of these features would be selected. If faults or fractures are present, however, the initial investigation would also need to demonstrate that they have low permeability and/or they are closed. For example, a considerable amount of effort has been devoted to the development of procedures for assessing fault seal capacity in hydrocarbon reservoirs (Yielding, 2002).

2.1 Poor Cement Emplacement in Enlarged Boreholes

During drilling operations, shear yielding and detachment of yielded rock from the borehole wall may result in severely enlarged and rugose boreholes. The extent of this enlargement is a direct function of in-situ stress magnitudes, rock compressive strength and drilling mud density (e.g., Hawkes and McLellan, 1999). Caprocks, which most often are shales, tend to be relatively weak and prone to yielding and enlargement. Casing-cement-formation bond quality is adversely affected by enlarged hole conditions. As such, determination of in-situ stress magnitudes can be used to design better drilling programs to avoid

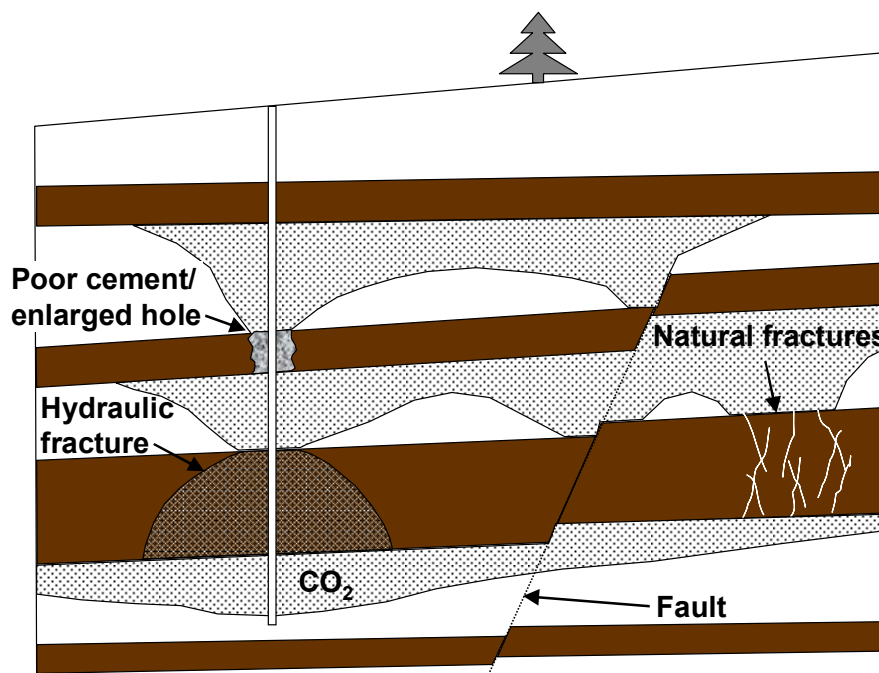


Figure 1: Possible CO₂ leakage pathways affected by in-situ stresses.

these problems in new wells, or to back-analyze yielding around existing wells to identify those with the greatest risk of enlargement.

2.2 Re-Activation (Slip) and Re-Opening of Faults and Natural Fractures

The permeability of faults or natural fractures that initially act as seals may increase if the shear stresses acting on these weak interfaces reach critical levels. As described in Hawkes *et al.* (2004), an increase in pore pressure within a fault or fracture plane will increase the tendency to slip. In cases where elevated pore pressures do not migrate into the weak interfaces, but rather induce a global stress change by uniformly pervading the entire sequestration reservoir, the slip tendency of faults or fractures can either increase or decrease. The factors controlling this include in-situ stress magnitudes and orientations, and the orientation and friction angle of these weak interfaces. The most critical orientation for slip of faults or fractures is in a plane that is 45° from the maximum in-situ stress (σ_1), dipping in the direction of the minimum in-situ principal stress (σ_3).

Even if fractures or faults have low permeability, the stress changes induced in the reservoir during injection may re-open them. For example, if elevated, near-well pore pressures migrate even part way into a fault or fracture surface, the weak interface will be forced open once the pore pressure exceeds the in-situ stress acting normal to its surface. Once this process has initiated, and the weak interface is propped open at its mouth, continued injection will enable the propagation of the re-opening process deeper into the caprock.

The most critical orientation for re-opening of fractures and faults is in a plane normal to the minimum in-situ stress (σ_3) component. These weak interfaces can re-open once the injection pressure exceeds σ_3 . Similarly, the least critical orientation of fractures and faults is in a plane normal to the maximum in-situ

stress (σ_l). These weak interfaces will re-open only once the injection pressure exceeds σ_l . All other fracture orientations will re-open at injection pressures between σ_3 and σ_l .

2.3 Hydraulic Fracturing

During fluid injection, high bottom-hole pressures may induce a tensile stress state around the wellbore. If the induced tensile stress magnitude exceeds the rock's tensile strength, then a tensile fracture will develop. Assuming that the injection fluid is clear (i.e., contains no particulate matter that might plug the induced fracture), this tensile fracture will propagate. If it propagates upwards out of the injection zone, it can create a leakage pathway through the caprock.

For an intact, linear elastic rock and a non-penetrating fluid (i.e., within the time-frame of the fluid injection period, no pore pressure increase occurs in the rock matrix near the borehole wall), the theoretical value for the fracture breakdown pressure p_b is (Hubbert and Willis, 1957):

$$p_b = 3\sigma_{H \min} - \sigma_{H \max} - \alpha p_{res} + T_s \quad (1)$$

where: $\sigma_{H \min}$ = minimum horizontal in-situ stress
 $\sigma_{H \max}$ = maximum horizontal in-situ stress
 p_{res} = reservoir pore pressure
 α = Biot's coefficient, equal to $1 - \frac{K_{bulk}}{K_{grain}}$
 K_{bulk} = static bulk modulus of porous rock
 K_{grain} = static bulk modulus of constituent mineral grains
 T_s = rock tensile strength

Although based on a number of idealized, simplifying assumptions, equation (1) shows that fracture breakdown pressures should be greater than the minimum horizontal in-situ stress magnitude.

Factors that can cause fracture breakdown pressures to deviate from the value predicted by equation (1) include near-well pore pressure increase during injection, non-linear rock properties, thermally-induced stresses, and the presence of natural fractures in the injection zone. In the case of the latter, so-called fracture breakdown may actually occur as the re-opening of these existing fractures, as discussed in the preceding section.

Figure 2 summarizes the relationship of injection pressures to the leakage mechanisms described above. If natural fractures or faults are present, then bottom-hole injection pressures higher than the minimum in-situ stress may open these fractures. Pressures higher than the fracture breakdown pressure will fracture the reservoir and/or caprock. In both instances, the injected fluid, in this case CO₂ or acid gas, will leak from the sequestration reservoir. Thus, it is essential to properly estimate the minimum stress and fracture breakdown pressure and devise injection strategies that will maintain pressures below these at all times. Further, in settings where the in-situ stress state is highly anisotropic and critically-oriented faults or fractures are present, there is a need to determine the stress magnitudes and orientations in order to assess the threshold pressure at which a leakage event due to shear failure might occur.

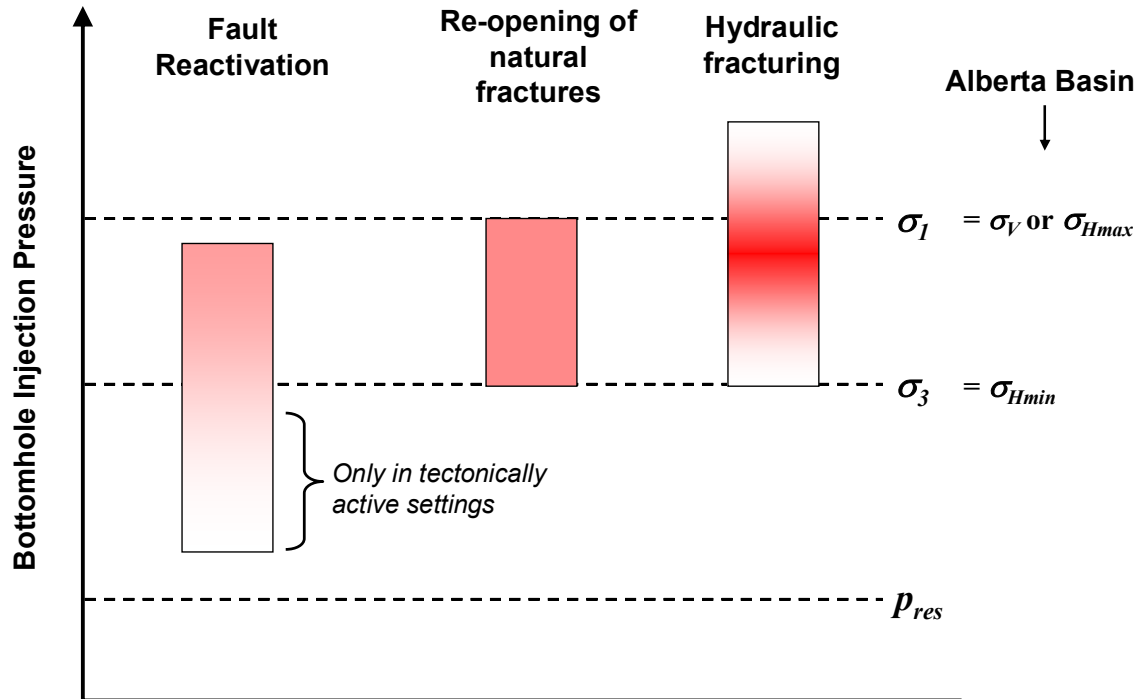


Figure 2: Important injection pressure thresholds that must be identified. The regions with the darkest shading denote pressures where the likelihood of inducing a leakage event is greatest.

3. IN-SITU STRESS DATA SOURCES AND TRADITIONAL INTERPRETATION METHODOLOGIES

3.1 Vertical Stress Magnitude

The vertical stress (σ_v) at any point in a basin is equivalent to the weight of the overburden. Integration of a bulk density log taken after drilling will provide the vertical stress at depth (D), according to:

$$\sigma_v = \int_0^D \rho_b dz \quad (2)$$

where ρ_b is the bulk density of the fluid-saturated rock. Density logs that are used for estimating σ_v should be as complete as possible and record little hole enlargement. In practically all wells there is an upper unlogged interval, and an average density for rock and near-surface deposits has to be assumed.

3.2 Minimum Horizontal Stress Magnitude from Fracture Closure Pressures

The minimum horizontal stress (σ_{Hmin}) can be estimated through various means. One way is using micro- and mini-fracture tests, extended leak-off tests and massive hydraulic fracture records to interpret the fracture closure pressure, which should correspond to the minimum stress magnitude (Figure 3). The accuracy of the estimates decreases from micro-fracture tests to massive hydraulic fractures. Micro-fracture tests involve initiating a hydraulic fracture within a short packed-off interval by slowly injecting

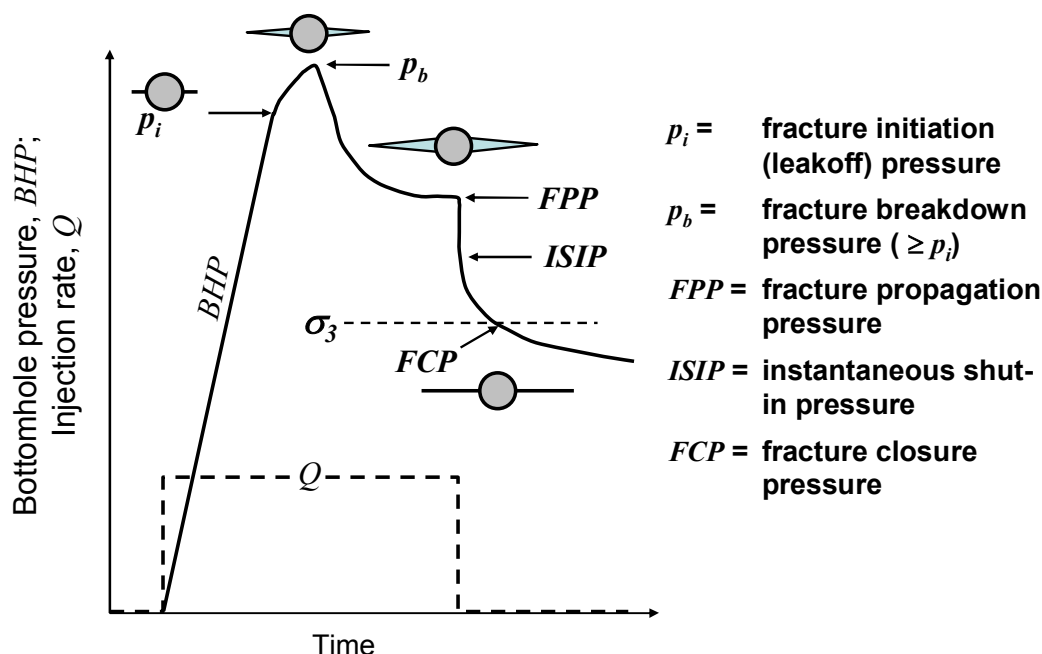


Figure 3: Typical pressure-time record for a micro- or mini-fracture test. Similar pressure-time records may be obtained from extended leak-off tests, although these test types are rare (none are available for the Alberta Basin). Fracture initiation pressure and fracture breakdown pressure may occur at the same point, especially in the case of a clear injection fluid (which has no particulate matter to plug the fracture once it initiates).

a small volume ($\sim 1 \text{ m}^3$) of a low-viscosity fluid (e.g., water), and opening and closing the fracture several times until a consistent closure pressure is obtained. If the fracture closure pressure is less than the overburden load (σ_v), then this pressure is equated with the smallest principal stress, i.e. σ_{Hmin} (Gronseth and Kry, 1983). Mini-fracture tests are similar to micro-fracture tests and typically involve a relatively high-rate injection of viscous fluids in excess of 10 m^3 (e.g., McLellan, 1988). The magnitude of σ_{Hmin} can be equated with fracture closure pressures interpreted from pressure versus time records, but these tests measure the average in-situ stress over a larger rock volume than the micro-fracture tests. Previous work in western Canada has shown that closure pressures from micro- and minifracture tests are practically indistinguishable (Woodland and Bell, 1989).

Table 1 lists the data that were used for this investigation. These data were extracted from a larger dataset, from which pressures that obviously had no relationship to stress magnitudes (e.g., unreasonably high or low) were filtered out. Of note is the fact that no fracture closure pressures were available for the 757 leak-off tests (because these were not extended leak-off tests), nor for the 583 massive hydraulic fracture stimulation treatments. The novel methods used to estimate σ_{Hmin} magnitudes from the leak-off and fracture breakdown pressures recorded for these tests will be discussed subsequently.

Table 1: Data available for minimum horizontal stress analysis in the Alberta Basin.

Parameter / Test Type	Number
Fracture closure pressure / Micro-fracture	15
Fracture closure pressure / Mini-fracture	91
Leak-off pressure / Leak-off test	757
Fracture breakdown pressure / Hydraulic fracture	583
Borehole breakout orientation / Oriented caliper log	248

3.3 Minimum Horizontal Stress Orientation

Stress orientations are important because they indicate the most likely direction of propagation for induced fractures, and they may provide clues as to the orientation of natural fractures. The most commonly used information for estimating stress orientations is derived from borehole breakouts (Bell, 2003). These breakouts are intervals in a well where caving has occurred on opposite sides of a borehole, so that it is laterally elongated, and are diagnostic of anisotropic compression around the borehole (i.e., $\sigma_{Hmin} \neq \sigma_{Hmax}$). In quasi-vertical wells ($<5^\circ$ from vertical) through transversely isotropic rocks, breakout caving elongates the wellbore parallel to σ_{Hmin} (Bell, 2003; Zoback *et al.*, 2003). Breakouts are best displayed on borehole imaging logs, but logging tools, such as dipmeters, are also suitable for documenting breakouts (Bell, 2003).

4. MINIMUM HORIZONTAL STRESS ESTIMATION FROM LEAK-OFF AND FRACTURE BREAKDOWN PRESSURES IN THE ALBERTA BASIN

Conventional leak-off tests are terminated once leak-off occurs. In these tests, leak-off is defined as the first point of deviation from a straight line on a plot of injection pressure versus injected volume. As such, it is not possible to observe fracture propagation, shut-in response and fracture closure. Figure 4 illustrates a typical leak-off pressure record, and lists the various mechanisms that may result in leak-off. Of greatest interest is the fact that leak-off will occur at pressures very close to σ_{Hmin} for cases where natural fractures oriented sub-normal to the σ_{Hmin} direction are present, or perhaps if fractures induced during a previous leak-off test are present (Figure 5). Consequently, if a large number of leak-off pressures have been recorded in a given region, a “lower bound” to these data should provide a reasonable estimate of σ_{Hmin} . The term “lower bound” is used loosely in this case, as there may be a few data points that fall at lower pressures, either due to a leak in the casing or cement, or into large pores or open natural fractures that cannot be plugged by the drilling mud solids. In general, it should be possible to differentiate these data points from the stress-related leak-off pressures, and draw a “lower bound” envelope that ignores them.

The underlying principle of the lower bound method may be visualized with the help of Figure 6. Successful application of the lower bound method has been demonstrated in the central North Sea by Edwards *et al.* (1998) and on the North West Shelf of Australia by Addis *et al.* (1998). To the authors’ knowledge, this technique has not been previously applied in the Alberta Basin.

4.1 Leak-off Pressure Analysis

In order to apply the lower bound method to the leak-off pressures (LOP) available for the Alberta Basin, it was first necessary to sub-divide the dataset geographically. Figure 7 shows the regional break-up that was ultimately used. For regions 2 through 4, the boundaries were drawn so as to encompass localized concentrations or clusters of data. Regions 1, 5, 6 and 7 were drawn in regions with lower data density, but in such a way as to group data points obtained from rocks of similar geologic age. Region 8 was drawn to encompass all remaining data points that are scattered throughout the eastern portion of the basin, but, because of its large areal spread, it is expected that the results would be less conclusive and representative.

Review of the leak-off pressures indicated that the majority of these measurements were made at relatively shallow depths. The greatest concentration occurred from 250 to 500 m, with most of the remaining data falling between 500 and 1000 m. As such, greatest confidence in the results obtained from leak-off tests is obtained only for these relatively shallow depths.

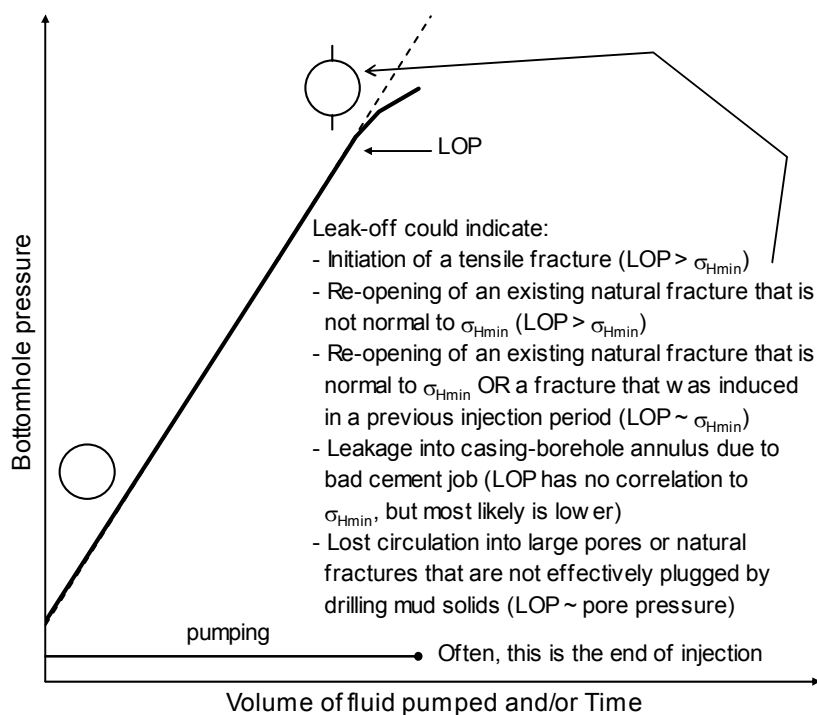


Figure 4: Pressure behavior for injection until just after leak-off occurs.

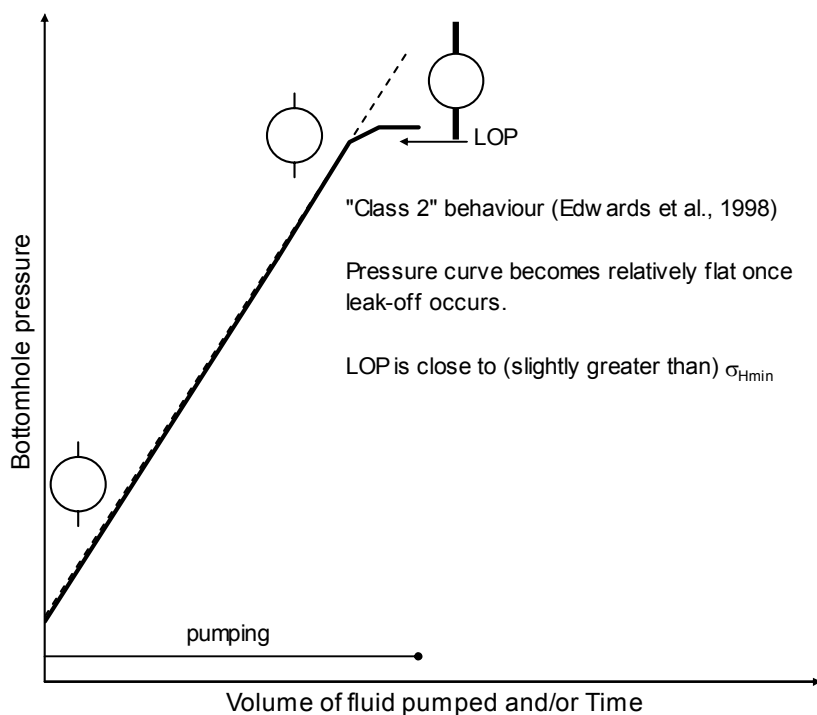


Figure 5: "Class 2" leak-off behavior observed if fracture(s) sub-normal to σ_{Hmin} are already present.

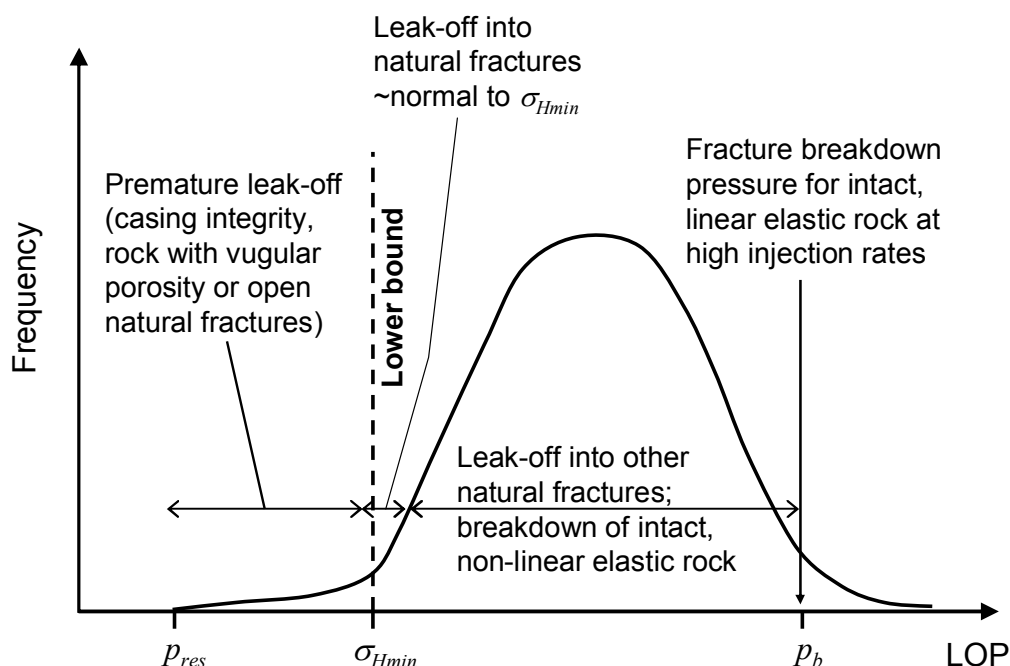


Figure 6: Conceptual illustration of the distribution of leak-off pressures with respect to in-situ stress magnitudes and reservoir pressure. A “Lower Bound” to the distribution of a large number of leak-off pressures is a reasonable estimate of σ_{Hmin} .

Figure 8 shows a plot of leak-off pressures versus depth for Region 3. This plot shows that a well-defined lower bound envelope exists, corresponding to a gradient of 17 kPa/m. Similarly well-defined lower bound envelopes, and similar stress gradients, were found for Regions 2 and 4. The quality of the lower bound envelopes ranged from moderate to poor for the other regions. A summary of the results for all regions, including comments on the confidence of the interpreted σ_{Hmin} values, is given in Table 2.

4.2 Fracture Breakdown Pressure Analysis

The mechanics of leak-off during a leak-off test and fracture breakdown during a hydraulic fracture treatment are essentially the same. In the case of an intact rock, leak-off and fracture breakdown pressures correspond to the pressure required to initiate a tensile fracture. This assessment is not always recognized; i.e., when leak-off tests are continued to the point of fracture breakdown, this breakdown pressure is often regarded as the fracture initiation pressure. However, given that the solids present in drilling muds tend to plug fractures when they initially form, fracture breakdown only occurs once a fracture has been initiated and has been opened to an aperture too wide to be plugged by the mud solids. When natural fractures are present, leak-off pressures and hydraulic “fracture breakdown” pressures actually correspond to the pressure at which the existing fractures are forced open. Consequently, a lower bound analysis of fracture breakdown pressures should also provide an estimate of the minimum stress.

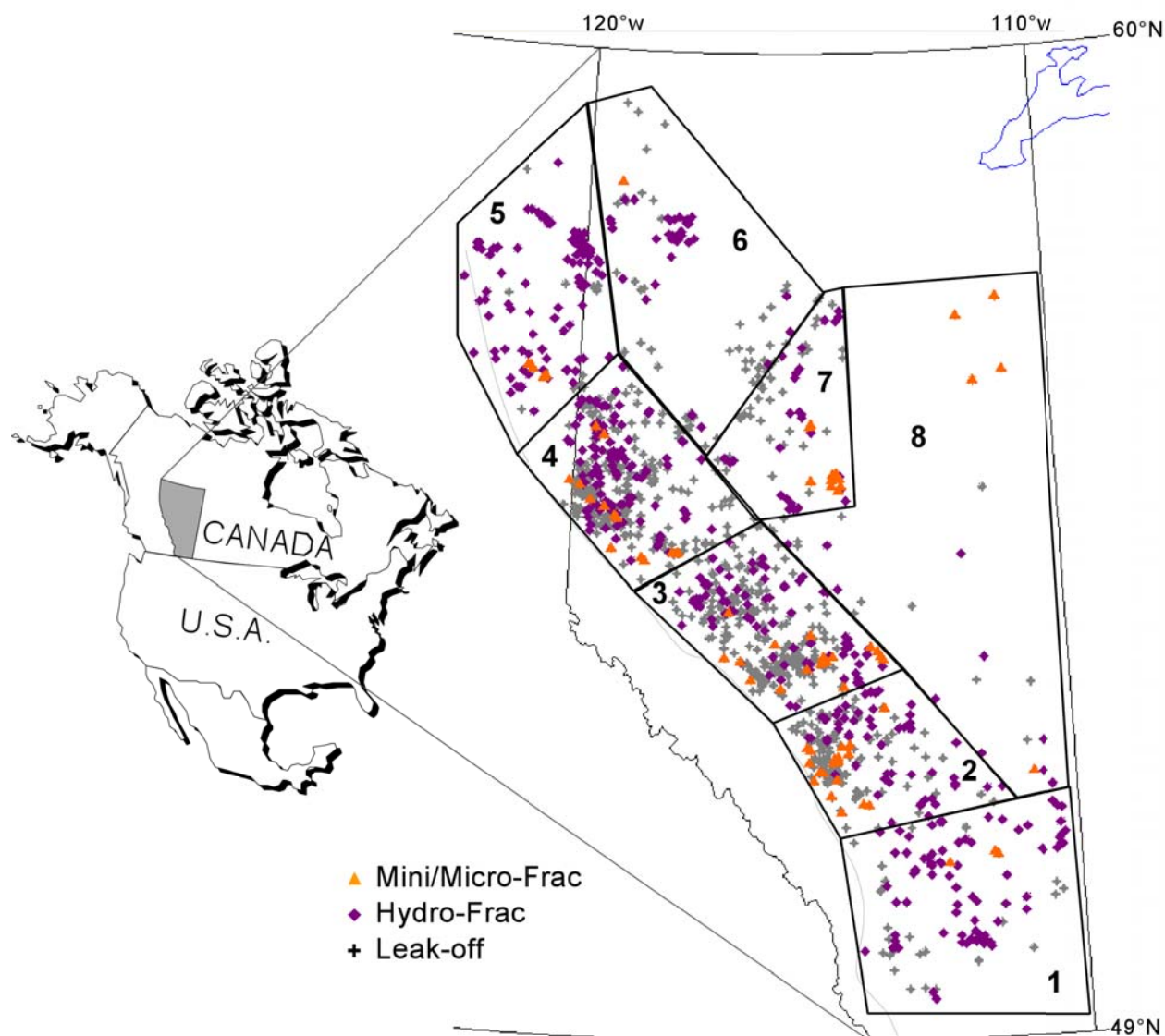


Figure 7: Sub-division of the Alberta Basin dataset into regions suitable for lower bound analysis of σ_{Hmin} .

Before proceeding to describe the analysis of fracture breakdown pressures, it is necessary to identify one significant difference between leak-off and fracture breakdown tests. Leak-off tests are typically run immediately below casing shoes, in non-reservoir rocks. As such, the pore pressures in these rocks are unaltered from their initial, in-situ values. Fracture breakdown pressures, on the other hand, are measured in reservoir formations that are about to be fracture stimulated. In many cases, these reservoirs have been produced for extended periods of time before the stimulation treatment. As such, pore pressures have often decreased significantly. This clarification is important because it has been demonstrated both theoretically and using field data that pressure depletion tends to lower σ_{Hmin} (e.g., Addis, 1997).

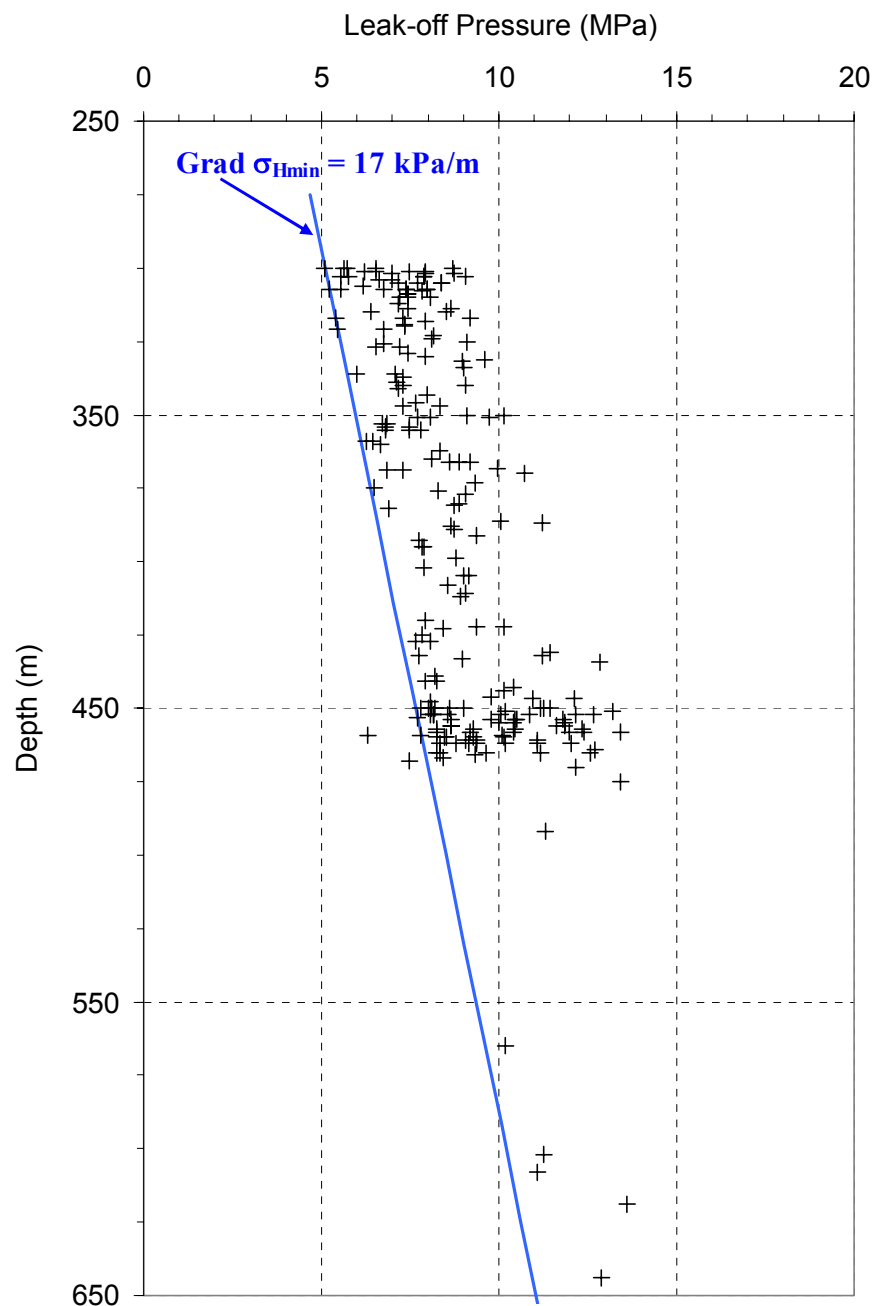


Figure 8: Depth profile showing leak-off pressures measured in Tertiary and Upper Cretaceous-age formations in Region 3 of the Alberta Basin. The lower bound to these data corresponds to a gradient the minimum horizontal stress of 17 kPa/m.

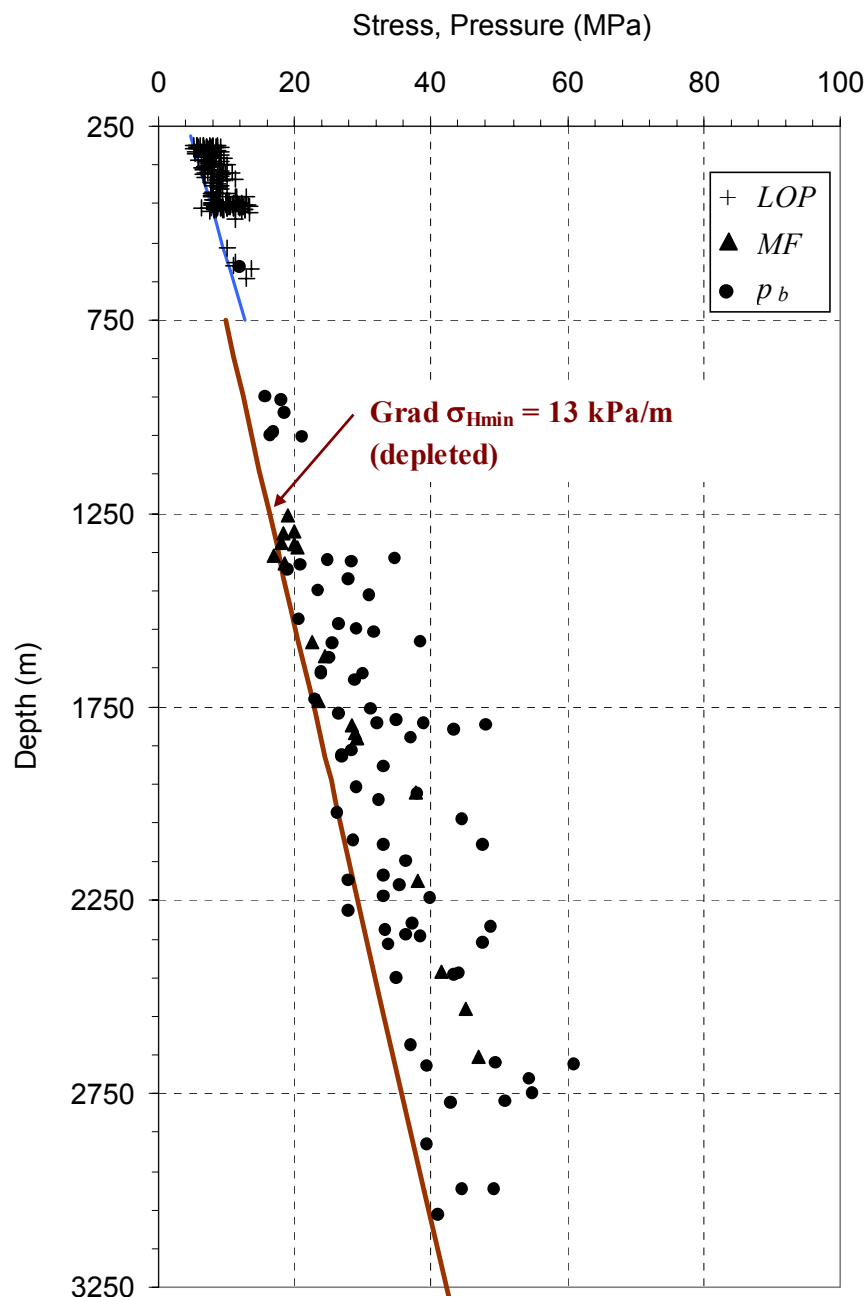


Figure 9: Depth profile showing leak-off pressures (LOP 's), fracture breakdown pressures (p_b) and fracture closure pressures from mini- and micro-fracture tests (MF) in Region 3 of the Alberta Basin. The different geologic ages included in the dataset shown include Tertiary, Upper Cretaceous, Lower Cretaceous, Carboniferous through Jurassic, and Devonian. The lower bound to the fracture breakdown pressures below 800 m corresponds to a gradient of 13 kPa/m. The fracture closure pressures that fall on this lower bound envelope were likely measured in pressure-depleted reservoirs, whereas the closure pressures above the envelope were likely measured in reservoirs that have experienced little or no depletion.

Table 2: Summary of S_{Hmin} gradients interpreted from lower bound analysis of leak-off and fracture breakdown pressures in the Alberta Basin.

Region	Leak-Off Pressures (LOP)		Fracture Breakdown Pressures (p_b)		Comment
	Depth and Age	S_{Hmin} gradient	Depth and Age	S_{Hmin} Gradient	
1	300-600 m Tertiary – Upper Cretaceous	18.0 kPa/m	600-2300 m U. Cretaceous - Devonian	14.0 kPa/m	Shallow: Sparse data, but well-defined envelope. Deep: Well-defined envelope; sparse data below 1500 m
2	300-700 m Tertiary – Upper Cretaceous	17.2 kPa/m	700-3000 m U. Cretaceous - Devonian	13.0 kPa/m	Shallow: Well-defined envelope; sparse data below 450 m. Deep: Well-defined envelope.
3	250-1000 m Tertiary – Upper Cretaceous	17.0 kPa/m	1000-3000 m U. Cretaceous – Devonian	12.9 kPa/m	Shallow: Well-defined envelope; sparse data below 500 m. Deep: Well-defined envelope.
4	300-700 m Tertiary – Lower Cretaceous	17.0 kPa/m	700-3200 m U. Cretaceous - Devonian	13.0 kPa/m	Shallow: Well-defined envelope; sparse data below 500 m. Deep: Well-defined envelope; sparse data below 2700 m.
5	500-1100 Jurassic-Carb.	12.8 kPa/m*	1100-2400 Jurassic-Carb.	12.0 increasing to 19.0 kPa/m	*Shallow: Based on fracture breakdown pressures. Well-defined envelope. Deep: Sparse data, but well-defined envelope.
6	300-800 Lower Cretaceous	15.0 kPa/m*	800-2300 m L. Cretaceous – Carboniferous	14.0 kPa/m	*Shallow: Based on fracture breakdown pressures. Sparse data. LOP 's affected by premature leak-off. Deep: Sparse data.
7	600-1500 m Devonian*	17.0 kPa/m*	1500-2400 m Devonian	13.0 kPa/m	*Shallow: Based on LOP 's and p_b 's. Sparse data. Deep: Sparse data.
8	200-1100 m Cretaceous	17.0 kPa/m*	1100-2100 m L. Cretaceous-Devonian	12.0 increasing to 16.5 kPa/m L. Cretaceous - Carboniferous	*Shallow: Sparse data. Based on LOP 's, p_b 's and mini-frac closure pressures. Deep: Sparse data. Based on p_b 's and mini-frac closure pressures.

Based on the arguments presented above, a lower bound analysis was attempted on fracture breakdown pressures measured in the Alberta Basin. Figure 9 shows for illustration the results obtained for Region 3. Similar to the results obtained at shallower depths for leak-off pressures, a well-defined lower bound envelope can be defined. In this case, the envelope corresponds to a gradient of 13 kPa/m. Given that this gradient is significantly lower than the 17 kPa/m measured at shallower depths, it is felt that the 13 kPa/m gradient is only valid for reservoirs that have been pressure-depleted. Similarly well-defined envelopes for breakdown pressures were obtained for Regions 1, 2, 4 and 5. Results ranging from moderate to poor were obtained for regions 6, 7 and 8.

Regarding Figure 9, it is worth noting that a common envelope seems to exist for rocks of various lithologies and all ages in Region 3, and this has been observed in other regions of the basin as well. This is significant because the analyzed sedimentary succession includes carbonate-dominated Devonian and Carboniferous strata deposited during the platform-margin stage of evolution of the Alberta Basin, as well as Jurassic to Tertiary-age siliciclastics deposited during the foreland stage. Apparently, any contrasts in horizontal stresses due to the different mechanical properties of these rocks are too small to affect the lower bound method.

As it currently stands, the regional lower bound envelopes derived from fracture breakdown pressures would lead to upper limits on injection pressures that are conservative (low) for non-depleted CO₂ storage sites. Efforts to characterize the stress-depletion response of reservoirs in the Alberta Basin are currently ongoing. With further analysis of each region, it may become possible to generate a set of lower bound envelopes that are differentiated based on pore pressure, enabling more appropriate minimum horizontal in-situ stress estimates at specific sites. Alternatively, as described in the following section on acid-gas injection sites, it is possible to apply the lower bound methodology in a localized sense, to obtain minimum horizontal in-situ stress estimates that are site-specific.

5. STRESS REGIMES FOR ACID-GAS INJECTION SITES IN THE ALBERTA BASIN

Acid-gas, a mixture of CO₂ and H₂S that is produced from sour gas reservoirs in western Canada, has been injected into deep geological formations for close to 15 years with a good safety record. Injection currently takes place at 44 sites into depleted oil and gas reservoirs, and deep saline aquifers (Figure 10). Injection at 5 sites has been rescinded, and at 2 other sites it has been suspended by the regulatory agency because the injection reservoir has been repressurized above the approved limit. One operation, although approved, has never been implemented. In a few cases there are two and even three sites at the same geographic location because acid gas is injected into different sequestration reservoirs. The average injection depth varies between 824 and 3432 m. At roughly 60% of the sites injection takes or took place in carbonate rocks, and the balance is or was injected into siliciclastics. In most cases shales and shaly siliciclastics constitute the overlying caprock. The remainder of the injection zones are confined by tight limestones, evaporites and anhydrites. Close to 5 Mt of acid-gas have been injected by the end of 2003 at a cumulative annual rate of ~1 Mt/year. In many ways, the acid-gas injection operations in western Canada constitute a commercial-scale analogue for CO₂ geological sequestration, and a more detailed history and description of these operations, including regulatory requirements, can be found in Bachu and Gunter (2004, 2005) and Bachu and Haug (2005).

Of particular importance in the permitting process and the operation of acid gas injection sites is avoidance of acid gas migration from the injection zone to other formations, shallow groundwater and/or the surface. To avoid migration through fractures, the injection zone should be free of natural fractures and the bottom hole injection pressure must be at all times below a certain threshold to ensure that

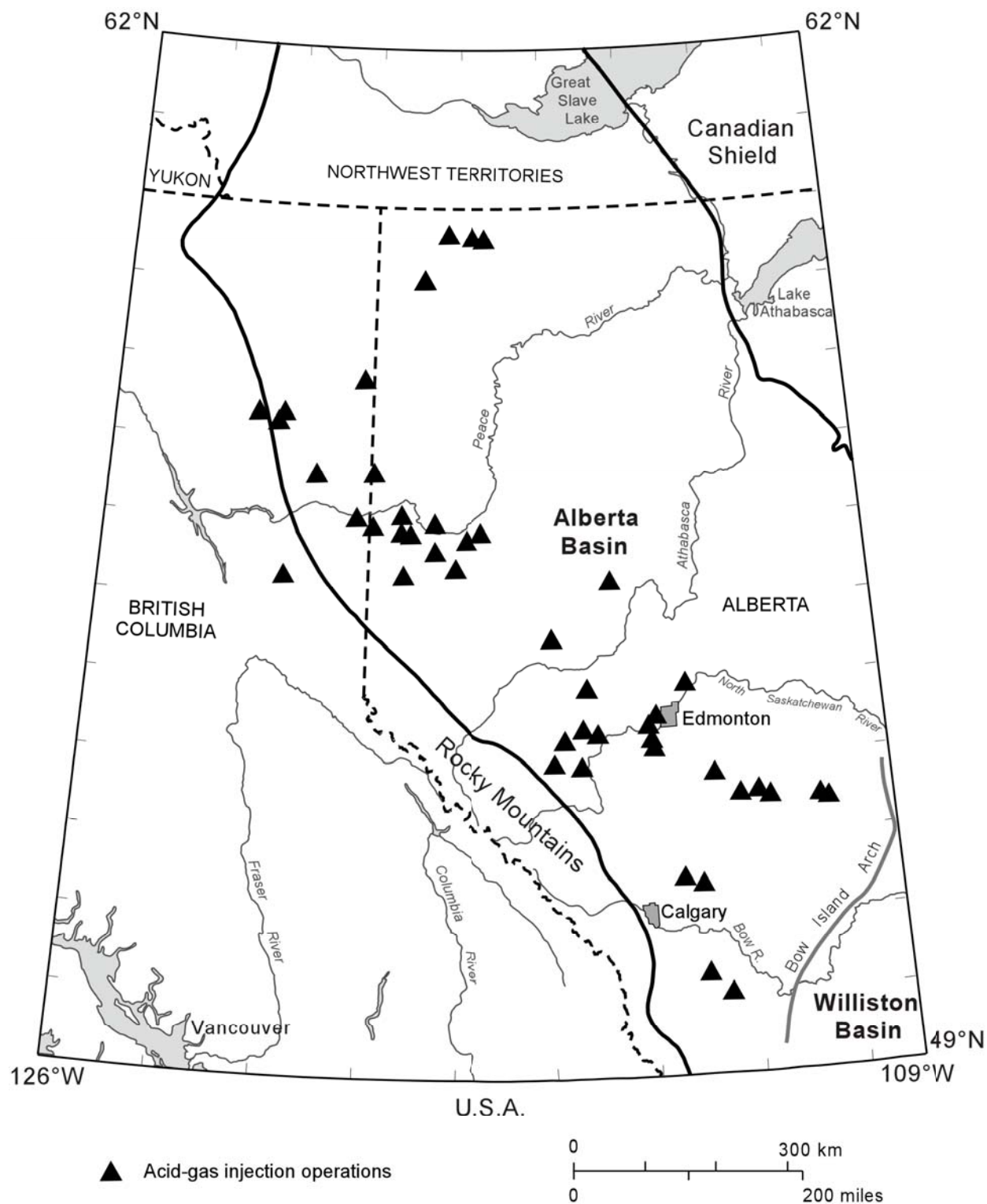


Figure 10: Location and status of acid-gas injection operations in the Alberta Basin at the end of 2004.

fracturing is not induced. In the case of acid gas injection into deep saline aquifers, the maximum bottom hole injection pressure is usually set at 90% of the rock “fracture pressure” (which is equivalent to the fracture breakdown pressure, p_b , used elsewhere in this paper). In the case of injection into depleted oil or gas reservoirs, lately regulatory agencies are setting the maximum bottom hole injection pressure to the initial reservoir pressure to avoid possible reservoir damage during production.

5.1 In-Situ Stress Regime

The methods described earlier in this paper were used to interpret the stress regime at each of the acid-gas injection sites, although they were applied at a more localized scale around each injection site. For example, to estimate σ_{Hmin} at a given site, the leak-off or breakdown pressure with the lowest gradient was selected from nearby wells. This essentially corresponds to the lower bound method described earlier. Vertical stresses were obtained by interpolation between values calculated from the nearest wells for which bulk density logs were available, including sometimes the injection well itself.

Minimum horizontal stresses, varying between 10.6 MPa at 705 m depth and 58.9 MPa at 3386 m depth, increase with depth with a basin-wide average gradient of 16.6 kPa/m ($R^2=0.935$; Figure 11), although stress gradients vary locally between 13.6 and 19.5 kPa/m. Maximum vertical stresses vary between 15.2 MPa at 705 m depth and 79.1 MPa at 3386 m depth, with local vertical stress gradients that vary between 21.2 and 25.2 kPa/m. Vertical stresses increase with depth with a basin-wide gradient of 23.8 kPa/m (Figure 11). The maximum horizontal stress (σ_{Hmax}), which cannot be estimated with confidence from the available data, has a value between these σ_{Hmin} and σ_V .

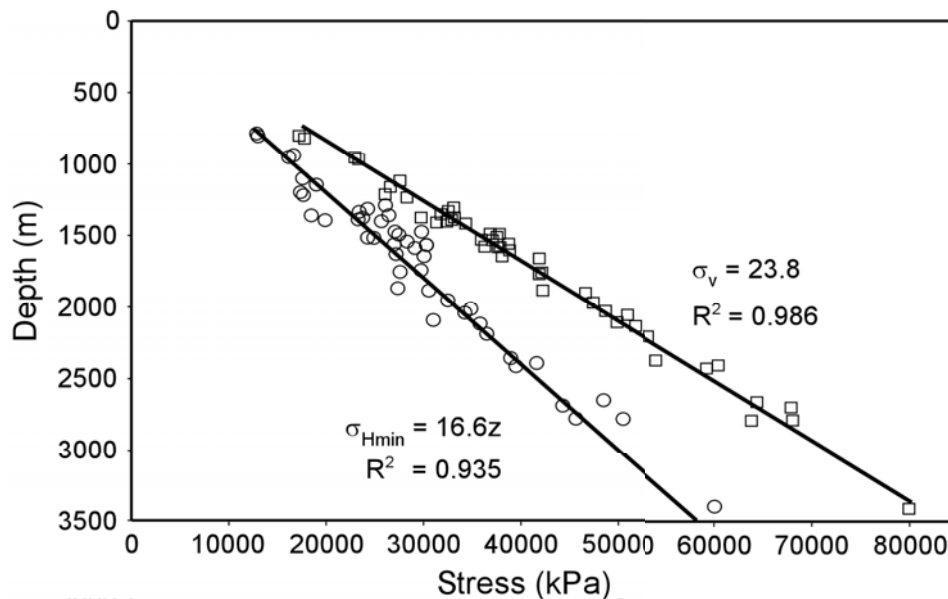


Figure 11: Variation with depth of minimum horizontal stresses at acid-gas injection sites in western Canada.

Borehole breakouts in wells across the basin were used to map stress trajectories at the basin level, as previously done for the entire Western Canada Sedimentary Basin and for the coal-bearing Cretaceous – Tertiary strata in southern and central Alberta (Bell *et al.*, 1994; Bell and Bachu, 2003). The direction of the maximum horizontal stress (σ_{Hmax}) in the Alberta Basin is generally normal to the Rocky Mountain Deformation Front (hence the direction of σ_{Hmin} is parallel to it). This suggests that a certain level of tectonic stress, caused by past orogenic processes, is present in the basin. The directions of the minimum and maximum horizontal stresses at the acid-gas injection sites were obtained using this dataset through interpolation or extrapolation, and vary between 22°N and 60°N. The practical value of the interpreted orientations is that, if tensile fractures occur, they will develop in the plane normal to σ_{Hmin} ; i.e., in the direction of σ_{Hmax} perpendicular to the Rocky Mountains.

5.2 Comparison of Injection and Fracture Pressures

As shown in Figure 12, minimum horizontal stresses are greater than the maximum bottom hole injection pressure (*BHIP*) licensed by the regulatory agency in all but one case. Operators usually inject at lower pressures than the maximum approved one, but occasionally may reach this value. Only at one site, rescinded in June 1999, the σ_{Hmin} value determined in this investigation is less than the maximum *BHIP*; however, given the modest accuracy of these stress estimates, it is quite possible that σ_{Hmin} is in reality greater than the maximum *BHIP*. Furthermore, the average wellhead injection pressure at this site was less by 1,000 kPa than the maximum approved wellhead injection pressure (*WHIP*). The data indicate that, at these acid-gas injection sites, at no time was there any danger of opening existing fractures, if any are present, as a result of injection.

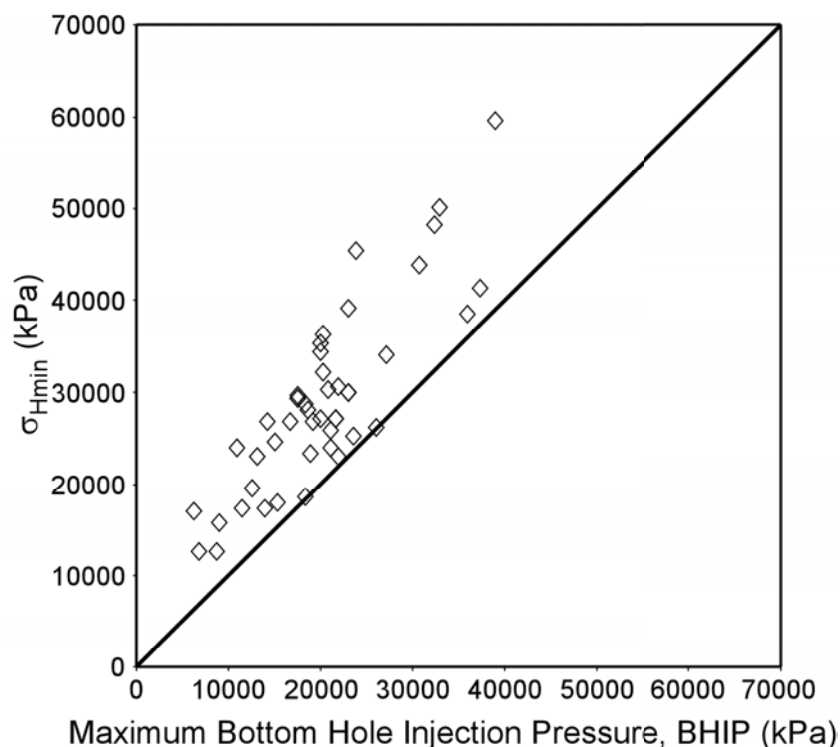


Figure 12: Relation between the minimum horizontal stress (σ_{Hmin}) and maximum bottomhole injection pressure (*BHIP*) at acid-gas injection sites in western Canada.

In the approval process, regulatory agencies in western Canada require operators to indicate the rock fracturing pressure in the sequestration reservoir and its confining caprock, and operators have used a variety of means to estimate it. In eleven cases the operator performed an injectivity test in the injection well itself. In four other cases the operators estimated the fracturing pressure on the basis of tests run in the corresponding sequestration reservoir in neighboring wells (mini-fracture tests, hydraulic and acid fracture stimulation jobs). In 30 cases the fracturing pressure was estimated on the basis of various types of calculated estimates for fracture gradients, and in seven cases no value or estimate was provided.

Figure 13 shows the variation with depth of the fracturing pressure as provided by operators in their applications to the regulatory agencies, showing an increase with depth in the range from 14,000 to ~61,000 kPa, with an average gradient of 19 kPa/m. In all cases minimum horizontal stresses are less than the fracturing pressure (Figure 13), on average by 12.3%, although they vary from as low as 58% to as high as 98% of the fracture pressure. The wide variability in the ratio between these parameters is partly due to the fact that most of the values were estimated rather than measured, and also due to the variable nature of fracturing (i.e., fracture breakdown) mechanisms, as discussed previously (see Figure 6). The character of the data shown in Figure 14 also confirms that authors' belief that the lower bound to many fracture breakdown pressures should be close to σ_{Hmin} . It should be pointed out, however, that in several cases the proximity of fracture pressure to σ_{Hmin} is likely due to the fact that, unless fracture pressure is measured, the operators prefer to be conservative and underestimate its value in their calculations, thus ensuring the safety of their operations.

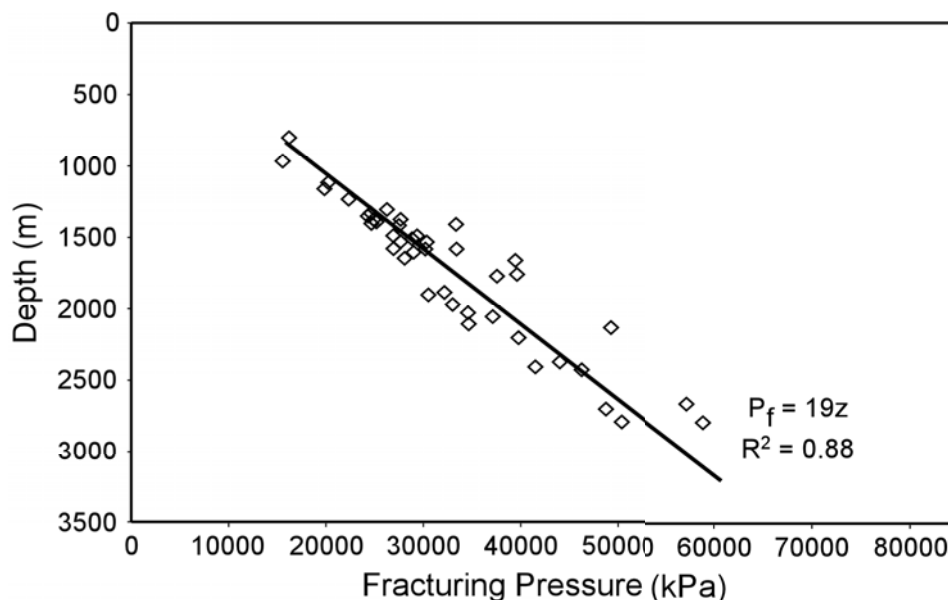


Figure 13: Variation with depth of fracturing pressure at acid-gas injection sites in the Alberta Basin, as indicated by operators.

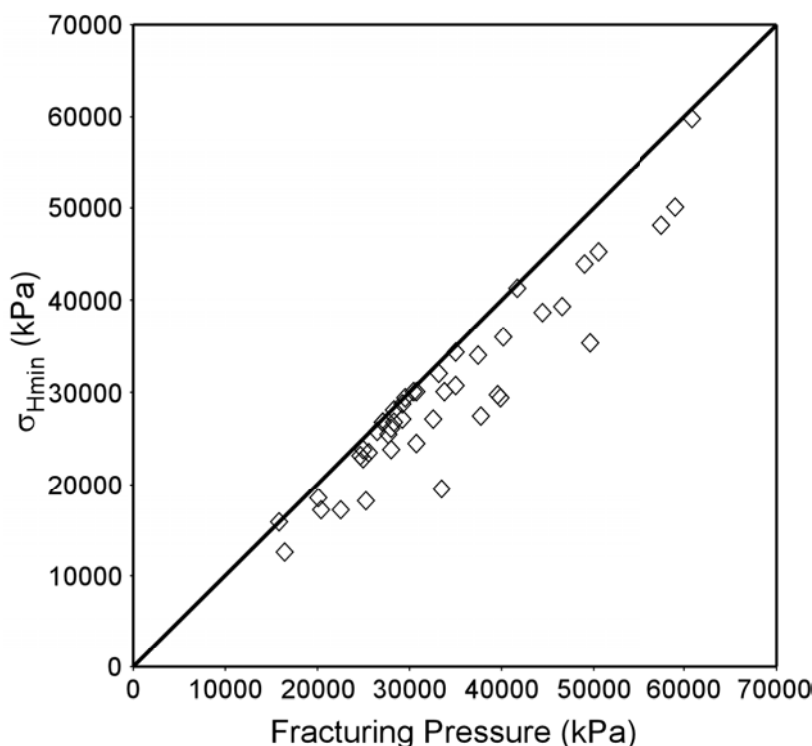


Figure 14: Relation between the minimum horizontal stress (σ_{Hmin}) and fracturing pressure at acid-gas injection sites in western Canada.

6. CONCLUSIONS

- In-situ stress magnitudes have a significant impact on the performance of CO₂ geological sequestration sites. They control the likelihood of such potential leakage events as hydraulic fracturing, re-opening or shearing of natural fractures and faults, and leakage up wellbores due to enlarged hole conditions.
- A relatively novel “lower bound” methodology has been used in the Alberta Basin to estimate minimum horizontal stress magnitudes from leak-off and fracture breakdown pressures obtained by industry drilling and fracture stimulation operations, respectively.
- Minimum horizontal stress gradients close to 17 kPa/m have been estimated for much of the Alberta Basin from leak-off tests conducted over depths from ~250 to ~1000 m in rocks that have not been affected by pressure depletion caused by reservoir production.
- Minimum horizontal stresses, with an estimated gradient close to 13 kPa/m for depths ranging from ~1000 to ~2500 m, were interpreted at a regional scale on the basis of fracture breakdown pressures, and are believed to be affected by reservoir depletion.
- In-situ stresses have been estimated using conventional and “lower bound” techniques at approximately 50 sites in western Canada where injection has successfully disposed of more than 5

Mt of acid gas over the past 15 years, and a basin-wide average gradient of 16.6 kPa/m has been determined for these sites. This result is consistent with the minimum horizontal stress gradient of 17 kPa/m found from leak-off tests.

- Maximum bottom hole injection pressures at the acid-gas injection operations in western Canada are safely below the minimum horizontal stress. Thus, there has been no driving mechanism to re-opening pre-existing fractures, if any exist.
- Minimum horizontal stresses are lower by 12.3% on average than rock fracturing pressures, thus there has been no driving force to induce new fractures.
- Minimum horizontal stresses are 30% less on average than the vertical stress at the injection sites, confirming that fractures in the Alberta Basin are vertical, except in some shallow zones (a few hundred meters deep) in the northeast at the basin edge.
- The orientation of induced fractures would be perpendicular to the Rocky Mountain Deformation Front, varying between ~22 and 60 degrees North at the acid-gas injection sites.
- This investigation has demonstrated techniques for estimating minimum stresses using commonly available industry data. However, to avoid overly conservative limits on injection pressures, it is suggested that hydraulic tests should be conducted at each potential sequestration site to determine the minimum stress magnitude (σ_{Hmin}) and further to assess if the fracture pressure significantly exceeds σ_{Hmin} .

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